NON-PUBLIC?: N
ACCESSION #: 9107190202
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Salem Generating Station - Unit 1 PAGE: 1 OF 08

DOCKET NUMBER: 05000272

TITLE: Reactor Trip From 100% Power Due To Lightning Strike

EVENT DATE: 06/16/91 LER #: 91-024-00 REPORT DATE: 07/15/91

OTHER FACILITIES INVOLVED: Salem Unit 2 DOCKET NO: 05000311

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER:
NAME: M. J. Pollack - LER Coordinator TELEPHONE: (609) 339-2022

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On June 16, 1991, at 1940 hours, during normal full power operation, Salem Unit 1 experienced a Reactor Trip/Turbine Trip. The first out overhead annunciation was "4KV Group Bus Undervoltage". At the time of the event a severe thunderstorm was in progress. Investigation revealed that lightning had struck in the vicinity of the phase B Generator Step-Up (GSU) transformer (EL). Evidence of the lightning strike included carbonization of the high voltage bushing, damage to the corona rings and lightning arrestor and eyewitness accounts. The root cause of the reactor trip event is attributed to an act of nature; i.e., a lightning strike in the vicinity of the phase B GSU transformer, resulted in a 4KV Group Bus Undervoltage and subsequent reactor trip. Lightning protection was assessed by engineering and found to be appropriate. The damage to the Phase B GSU transformer was repaired. Subsequently, on June 24, 1991, the Unit 1 was returned to service. Also as a result of the lightning strike, 500 KV breaker flashover protection was initiated

due to sufficient current through the transformer neutral. This resulted in the loss of the No. 2 Station Power Transformer and subsequent de-energization of the 1F and 1G Group Busses. An engineering review has been initiated to prevent flashover protection actuation from a coasting generator. Design changes will be implemented as appropriate.

END OF ABSTRACT

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as {xx}

IDENTIFICATION OF OCCURRENCE:

Reactor Trip from 100% power due to lightning strike

Event Date: 6/16/91

Report Date: 7/15/91

This report was initiated by Incident Report Nos. 91-441, 91-442, 91-443, 91-444, and 91-479.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 1 Reactor Power 100% - Unit Load 1142 MWe

DESCRIPTION OF OCCURRENCE:

On June 16, 1991 at 1940 hours, during normal full power operation, Salem Unit 1 experienced a Reactor Trip/Turbine Trip. The first out overhead annunciation was "4KV Group Bus Undervoltage".

At the time of the event a severe thunderstorm was in progress. Investigation revealed that lightning had struck in the vicinity of the phase B Generator Step-Up (GSU) transformer {EL}. Evidence of the lightning strike included carbonization of the high voltage bushing, damage to the corona rings and lightning arrestor and eyewitness accounts.

The Nuclear Regulatory Commission (NRC) was notified of the actuation of the Reactor Protection System (RPS) {JC} at 2037 hours on June 16, 1991 in accordance with Code of Federal Regulations 10CFR 50.72(b)(2)(ii).

APPARENT CAUSE OF OCCURRENCE:

The root cause of the Salem Unit 1 June 16, 1991 reactor trip event is attributed to an act of nature. At 1940 hours, a lightning strike in the vicinity of the phase B GSU transformer, resulted in a 4KV Group Bus Undervoltage and subsequent reactor trip. Lightning protection was assessed by engineering and was found to be appropriate.

SEQUENCE OF EVENTS:

Refer to the attached schematic, for additional details, when reviewing this section and the Analysis of Occurrence section.

SEQUENCE OF EVENTS: (cont'd)

Date/Time Event

7-16/1940 Lightning strike in vicinity of Phase B of the Main Power Transformer (i.e., GST)

Electrical fault on 500 KV Main Power Transformer

Unit 1 Generator Differential Regular and Backup Trip Relays actuate

500 KV Breakers open (10X and 12X); Generator Field Breaker opens and Turbine Trip signal initiated

4KV Group Busses transfer initiates; from the Auxiliary Power Transformer to the Nos. 11 and 12 Station Power Transformers

Rx Trip Breakers open

4KV Group Bus transfer complete and Bus voltage returns to normal

Flashover protection relays and alarms (Salem Units 1 and 2) actuate (t sub o + 4 seconds)

12 and 22 Station Power Transformers trip

1B Vital Bus Transfers to 11 SPT

2B Vital Bus Transfers to 21 SPT

1F and 1G Group Busses deenergize and alarm in Control Room

ANALYSIS OF OCCURRENCE:

Following the GSU transformer lightning strike, the resultant phase to ground fault operated the generator differential regular and backup instantaneous trip relays on Phases B and C GSU transformers opening the 10X and 12X 500 KV breakers, opening the generator field breaker and causing a Unit 1 turbine trip (Unit Isolation Trip). The Unit Isolation Trip subsequently initiated a Group Bus transfer (i.e., fast transfer scheme) from the Auxiliary Power Transformer to the Nos. 11 and 12 Station Power Transformers, respectively.

It is not uncommon, when you have single phase to ground faults, for only two (2) of the three (3) phases to pick-up the instantaneous relays initiating the Unit Isolation Trip (i.e., Phase A instantaneous relays did not pick-up).

At the time of the Phase B phase to ground fault, voltages on the

ANALYSIS OF OCCURRENCE: (cont'd)

electric distribution system for the four (4) 4KV Group Busses and the three (3) 4KV Vital Busses decayed. All 4KV Vital Bus voltages recovered within 4 cycles while the Group Bus voltages recovered after completion of the fast transfer (in approximately 12 cycles). This degraded Group Bus voltage (below 70% rated voltage) lasted sufficiently long to initiate a Reactor Trip signal via the Group Bus undervoltage relays.

Also as a result of the lightning strike, 500 KV breaker (10X and 12X) flashover protection initiated due to sufficient current through the transformer neutral. The flashover protection occurred four (4) seconds following the fault, on the phase B GSU transformer, causing: 1) all adjacent 500 KV breakers to open; 2) loss of half of the 13 KV ring bus (13 KV 4-5 and 3-4 breakers opened); 3) lockout of the Unit 3 (Gas Turbine) 13 KV breaker; 4) the New Freedom Line was remote tripped to the New Freedom Substation; and 5) isolation of the Salem New Freedom Line from Section 2 (of the 500 KV Switchyard).

Flashover protection actuation should have occurred approximately 13 cycles after fault occurrence. It could not be determined why flashover protection was delayed; however, the delay did not have an impact on this event. Testing was performed but the circuits timed correctly and the event could not be duplicated.

The loss of 500 KV power to Section 1 (of the 500 KV Switchyard) resulted in the loss of the No. 2 Station Power Transformer (SPT). With the loss of the No. 2 SPT, 13 KV power to the Nos. 12 and 22 SPTs was lost.

After the loss of the No. 12 SPT, the 1F and 1G Group Busses de-energized (i.e., the Auxiliary Power Transformer was already de-energized due to the Unit Isolation Trip signal) and the 1B Vital Bus successfully transferred from the No. 12 SPT to the No. 11 SPT.

Due to the loss of the No. 22 SPT, the 2B Vital Bus successfully transferred from No. 22 SPT to the No. 21 SPT.

An extensive analysis provided by oscillograph, digital fault recorder and sequence of events recorder records indicated that the relay operations were correct for the conditions. Although the breaker flashover scheme is designed to protect against the flashover of either 500 KV generator breaker, it also operates for a fault between the 500 KV generator breakers and the main transformer when the fault current is suppl
ed by the generator. There was no evidence, either oscillographic or physical, of the flashover of either 500 KV generator breaker. Therefore it is concluded that the flashover relay scheme was operated by the current contributed by the coasting generator. An Engineering review, along with appropriate modifications, has been initiated.

After the loss of the "1F" and "1G" Group Busses, the following

ANALYSIS OF OCCURRENCE: (cont'd)

significant equipment was de-energized:

1. Nos. 13 and 14 Reactor Coolant Pumps (RCPs); The loss of No. 13 RCP resulted in limited pressurizer spray capability; however, the No. 11 RCP was available for pressurizer spray and was successfully used.

2. Control Pressurizer Heaters and one set of Backup Pressurizer Heaters

3. Plant Vent composite sample pump; this pump is required to remain operable as per Technical Specification 3.3.3.9 Table 3.3-13. Chemistry was notified and alternate sampling was initiated. The pump was returned to service when 1F Group Bus was restored (at 0041 hours on June 17, 1991)

An excessive cooldown occurred following the reactor trip. This was due to Auxiliary Feedwater making up for Steam Generator shrink from the trip and loss of Nos. 13 and 14 Reactor Coolant Pumps. In accordance with the guidance provided by the EOPs, closure of the main steam isolation valves was successfully performed. Excessive cooldown is a concern identified from prior plant trips. Engineering has assessed this phenomenon and concluded that it does not pose a safety concern; however, corrective actions are being pursued (reference LER 311/91-029-00).

The 11MS10 atmospheric relief valve {SB} changed operational modes from automatic to manual and then went full open while reducing its setpoint (to 1005 psig) to control Steam Generator pressure. A work order was initiated to investigate and correct this concern.

Operator actions following the automatic actuation of the reactor trip began with the NCO initiating a manual trip. Procedure EOP-TRIP-1 was then entered followed by entry into EOP-TRIP-2. Actions required by these procedures were complied with including closure of the main steam isolation valves due to Tavg excessive cooldown. Operators compensated for the inadvertent full opening of the 11MS10 valve (following its setpoint adjustment), and subsequent lower level in No. 11 Steam Generator, by adjusting the Auxiliary Feedwater flow to the No. 11 Steam Generator. With the loss of the 1F and 1G Group Busses, the Control Pressurizer Heaters and one set of Backup Pressurizer Heaters were unavailable. Also, as stated above, the No. 13 RCP became unavailable. Using the available Backup Pressurizer Heaters and the No. 11 RCP Pressurizer spray capability Operators were able to to maintain RCS pressure control.

After completing the actions required by EOP-TRIP-1 and EOP-TRIP-2, IOP-8 was entered. Using this procedure, the plant was stabilized (in Mode 3) with the two (2) operating Reactor Coolant Pumps (i.e., Nos. 13 and 14 RCPs were not operating due to the loss of the 1F and 1G Group Busses). After stabilization of the plant, Technical Specifications were reviewed and required actions performed due to the loss of an off-site power source (Technical Specification 3.8.1.1 Action "a").

ANALYSIS OF OCCURRENCE: (cont'd)

Technical Specification 3.8.1.1 Action "a" states:

"With either an offsite circuit or diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a and 4.8.1.1.2.a2 within one hour and at least once per 8 hours thereafter; restore at least two offsite circuits and three diesel generators to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours."

Due to plant conditions, the Unit 1 Diesel Generators were successfully tested within one hour of Unit stabilization following the loss of the No. 2 Station Power Transformer (i.e., one of the two sources of offsite power) as per the Action Statement (on June 16, 1991 at 2154, 2155, and 2156 hours respectively). Preparations for testing the Diesel Generators was initiated approximately one hour and twenty minutes after the loss of the No. 2 Station Power Transformer. The delay in the testing of the Unit 1 diesel generators was therefore due to the time required to stabilize the Unit. However, it does constitute a noncompliance which is reportable to the Nuclear Regulatory Commission in accordance with Code of Federal Regulations 10CFR 50.73(a)(2)(i)(B).

Early in the Unit 1 event, the SNSS did initiate actions to perform an operability check of the Salem Unit 2 diesel generators. This was required, per Technical Specifications (identical to the Unit 1 Action requirements), due to the loss of the offsite power source (i.e., No. 2 Station Power Transformer). The Unit 2 Diesel Generators were successfully tested within one hour.

Also, following the loss of No. 2 SPT and the subsequent transfer of the No. 2B Vital Bus from the No. 22 SPT to the No. 21 SPT, a

Containment Purge/Pressure Vacuum Relief (CP/P-VR) isolation signal from the 2R41C Radiation Monitoring System (RMS) (IL) Plant Vent noble gas monitor actuated. At the time of this event, the CP/P-VR valves were closed. The root cause of the CP/P-VRS actuation is attributed to equipment design. As indicated in prior LERs (e.g., 311/90-033-00), the Salem Unit 2 RMS Victoreen equipment is prone to failure on voltage transients. CP/P-VR isolation is an Engineered Safety Feature; therefore, the NRC was notified of this actuation at 2324 hours on June 16, 1991 in accordance with Code of Federal Regulations 10CFR 50.72(b)(2)(ii).

Following the CP/P-VR isolation signal, the channel was reset and returned to service.

At the time of the lightning strike, the 1F Group Bus was supplying power to the Dimension Building Telephone House due to the normal UPS and diesel generator being cleared and tagged in support of

ANALYSIS OF OCCURRENCE: (cont'd)

corrective maintenance. The building includes the power for transmission (i.e., microwave) for the Emergency Notification System (ENS) telephone system. With the loss of the Group Bus, the house power supply was lost. Subsequently, the ENS phone system was made inoperable. Emergency notifications, required by the Code of Federal Regulations 10CFR 50.72, were made over the PSE&G private CENTREX microwave system.

Phone systems lost in addition to the ENS, due to the power loss to the Dimension Building Telephone House, included the "DID" system, the Nuclear Emergency Telephone System (NETS) to all on-site Emergency Response Facilities, the NAWAS (Delaware Backup) system and the U.S. Coast Guard Repeater.

As stated above, the ENS phone lines were disabled due to unavailability of the Dimension Building Telephone House power supply and the diesel generator. This supply had been cleared and tagged in support of corrective maintenance.

In conclusion, the Salem Unit 1 reactor trip of June 16, 1991, caused by an act of nature, resulted in limited consequence. The health and safety of the public was not affected. Once the event occurred the plant protective design features and operator performance were adequate. However, due to the actuation of the RPS and actuation of an ESF signal (CP/P-VR isolation), this report has been prepared in accordance with Code of Federal Regulations 10CFR 50.73(a)(2)(iv) requirements.

CORRECTIVE ACTION:

The damage to the Phase B GSU transformer was repaired. Subsequently, on June 24, 1991, the Unit 1 was returned to service.

A review of the lightning protection features, in use at Salem Station, was conducted by Engineering & Plant Betterment. It was found that these features are appropriate for transformer protection.

An Engineering review has been initiated to assess the prevention of flashover protection actuation for a fault between the 500 KV generator breakers and the main transformer when the fault current is supplied by the generator. Design changes will be implemented as appropriate. The Procedure Upgrade Project (PUP) effort will restructure the system operating procedures for the electrical system to provide necessary guidance for energizing dead busses including all necessary relays (with reset and prerequisite condition requirements).

Investigation of the inadvertent 11MS10 valve opening (full), when changing its setpoint, revealed that the "manual/auto controller" had failed. It was subsequently replaced.

Figure "Attachment Schematic" omitted.

ATTACHMENT 1 TO 9107190202 PAGE 1 OF 1

PSE&G
Public Service Electric and Gas Company P.O. Box 236
Hancocks Bridge, New Jersey 08038

Salem Generating Station

July 15, 1991

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Dear Sir:

SALEM GENERATING STATION
LICENSE NO. DPR-70
DOCKET NO. 50-272
UNIT NO. 1

LICENSEE EVENT REPORT 91-024-00

This Licensee Event Report is being submitted pursuant to the requirements of the Code of Federal Regulations 10CFR 50.73(a)(2)(iv) and 50.73(a)(2)(i)(B). This report is required to be issued within thirty (30) days of event discovery.

Sincerely yours,

C. A Vondra
General Manager -
Salem Operations

MJP:pc

Distribution

The Energy People

*** END OF DOCUMENT ***